How Crude?: Determining Transmission “Beneficiaries” and Related Steps Toward Workable Renewables Transmission Cost Allocation

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Factors including state renewable energy policies spur the need for construction of high-voltage electricity transmission lines in the United States. The question of which power customers within multi-state transmission organizations should bear construction costs persists as a realm of policy discord among power customers, utilities, and grid planners. Under the Federal Power Act, interstate transmission costs must be "just and reasonable," the statutory underpinning of the cost causation principle, by which courts review interstate transmission cost allocation plans. When transmission benefits accrue to a limited set of customers, allocation to them of corresponding construction costs is an easy choice. Problematically, certain construction benefits resist precise quantification and may accrue broadly, or over time. In Illinois Commerce Commission v. FERC, the Seventh Circuit upheld a transmission financing plan that spreads the cost of renewables transmission construction across member-utilities of the Midwest Independent System Operator (MISO) regional transmission organization, according to utilities' respective electricity draws from the MISO grid. This Note argues that MISO's approved cost allocation plan represents a step forward for renewables-to-grid integration, but does not create a sweeping rationale for similar cost-spreading allocation schemes. This Note further argues that if renewables-to-grid integration is to proceed unencumbered by ongoing, large-scale litigation, FERC or Congress should clarify three areas of transmission cost allocation ambiguity: (1) the definition of “benefits” under FERC Order 1000, (2) the necessary granularity of transmission cost/benefit analyses, and (3) the frequency of benefit-to-cost reporting on completed transmission projects.

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INTRODUCTION

The American electricity transmission system stands at a defining moment in its history. Aging infrastructure requires update and repair.1 Population growth drives a need for grid expansion and reliability improvements.2 Climate change drives efforts to phase out coal and other high-carbon-emissions energy sources.3 State and federal legislation encourages or mandates diversification of energy sources, driving investment in renewable energy sources (“renewables”) such as wind and solar.4 In sum, a coalescence of factors creates urgent need...
for transmission construction. 5

Informed by climate change science and a national concern about energy independence, thirty states and the District of Columbia have passed enforceable renewable portfolio standards (RPSs) or other mandated renewables policies. 6 These laws require that a set percentage of a state’s electricity come from renewable sources and often rely on wind and solar. 7 While wind and solar (“distance-transmitted” renewables) provide reliable sources of RPS fulfillment, their ideal siting often necessitates transmission over long distances and through the territories of different transmission organizations and states. Problematically, when a transmission organization spans multiple states, its decision to construct RPS-driven transmission to meet one state’s needs may entail organization-wide charges that affect customers in neighboring states with differing renewables public policies. 8 Before construction, transmission organizations seek to identify which customers within their territories will benefit from new transmission projects, but precise identification is not always possible. 9 Thus it is not always clear which customers should bear construction costs. Transmission projects cannot move forward without cost recovery certainty.

When project benefits accrue to a limited set of customers, allocation to that group is easy. When benefits extend widely within an organization, the organization may choose to socialize costs in order to capture all benefiting utilities, and in turn, electricity customers. Socialization—especially across large and geographically separate customer pools—requires specificity in identifying project beneficiaries, and the per-project benefit-to-cost ratios each incurs. Without sufficient clarity, electricity customers risk paying the costs of projects that will never benefit them.

Unfortunately, socialization analyses are fraught with complications.

5. See Ill. Commerce Comm’n v. Fed. Energy Regulatory Comm’n, (Illinois I) 576 F.3d 470, 478 (7th Cir. 2009) (Cudahy, J., concurring and dissenting) (“The United States is now engaged in an urgent project to upgrade its electric transmission grid, which for years has been generally regarded as inadequate, and may become more deficient with the addition of major new anticipated loads.”) (internal citations omitted); Feesshee, supra note 3, at 3–5; Silverstein, supra note 1.


8. See Klass & Wilson, supra note 7, at 1809–10.

9. See id. at 1870 (“Benefits may be hard to estimate, and some entities may feel that they are paying more for a line than they will gain in benefits.”); PJM INTERCONNECTION, supra note 2, at 18; SARI FINK ET AL., NAT’L RENEWABLE ENERGY LAB., A SURVEY OF TRANSMISSION COST ALLOCATION METHODOLOGIES FOR REGIONAL TRANSMISSION ORGANIZATIONS 2 (2011), available at http://www.nrel.gov/docs/fy11osti/49880.pdf (“Transmission cost allocation can be particularly contentious for multi-state transmission projects that cross more than one state, as the benefits of the proposed project may accrue unevenly to market participants.”).
Certain benefits, such as reliability through lessened outages, pose limits on calculability.\textsuperscript{10} Others resist quantification and are inherently forward-looking, including modernization of the grid through accommodating the advancement of renewables and decreases in fossil-fuel-based generation. Cost socialization may require customers to cover transmission intended to fulfill—among other objectives—other states’ RPSs.\textsuperscript{11} Socialization also presents the greatest likelihood of protracted, multi-party litigation, as utilities spar with regional transmission organization (RTO) grid planners and the Federal Energy Regulatory Commission (FERC) over just who fairly pays for which transmission project.

Rational electricity consumers do not wish to pay for costs they have not incurred, nor benefits they will never receive. The resulting utility and electricity customer outcry has attracted congressional attention,\textsuperscript{12} made timely by steady advances in state RPSs and renewables investment.\textsuperscript{13} If needed transmission construction is to proceed without unreasonable delay, grid planners require clarified parameters to determine when renewables transmission costs may be spread across customer pools.

No clear technical hurdle prevents having an energy grid by midcentury that runs on 80 percent renewables.\textsuperscript{14} Rather, the obstacles are, among others, complex planning issues, including transmission cost allocation.\textsuperscript{15} These costs are in the tens of billions of dollars.\textsuperscript{16} As renewables technology improves and investment increases, corresponding transmission demands will likely increase,

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\item \textsuperscript{10} Ill. Commerce Comm’n v. Fed. Energy Regulatory Comm’n, (Illinois II), 721 F.3d 764, 774 (7th Cir. 2013) (“Illinois ignores the limitations on calculability that the uncertainty of the future imposes.”).
\item \textsuperscript{11} For such a trans-state scenario, see Tina Seeley, ITC’s Green Power Express Would Carry U.S. Wind Power (Update2), BLOOMBERG (Feb. 9, 2009, 4:27 PM), http://www.bloomberg.com/apps/news?pid=newsarchive&sid=aSKqViph2Nj4; see also Gabe Maser, It’s Electric, but FERC’s Cost-Causation Boogie-Woogie Fails to Justify Socialized Costs for Renewable Transmission, 100 GEO. L.J. 1829, 1833 (2012) (discussing how ITC’s Green Power Express could force power customers in a non-RPS state to contribute to transmission costs primarily intended to fulfill RPS requirements of neighboring states).
\item \textsuperscript{12} See Powering America for Tomorrow Act, H.R. 2762, 113th Cong. § 2 (2013) (as referred to House Subcommittee on Energy and Power, July 6, 2013) (directing FERC to require that all regional high voltage transmission cost allocation processes adhere to a clear and consistent set of regulatory principles); S. 400, 112th Cong. § 1 (2011) (not enacted) (amending Section 205 of the Federal Power Act to mandate that permissible rates or charges be based on “an allocation of costs for new transmission facilities that is reasonably proportionate to measurable economic or reliability benefits projected, as determined by the Commission, to accrue to the 1 or more persons that pay the rate or charge”) (emphasis added); American Clean Energy Leadership Act of 2009, S. 1462, 111th Cong § 121 (2009) (not enacted) (directing FERC to issue a rule on national electricity grid planning principles to require that transmission costs not be “allocated to a region, or subregion, unless the costs are reasonably proportionate to measurable economic and reliability benefits”) (emphasis added); infra note 185.
\item \textsuperscript{14} See id.
\item \textsuperscript{15} See id.
\item \textsuperscript{16} RICHARD J. CAMPBELL & ADAM VANN, CONG. RESEARCH SERV., REP. NO. R41193, ELECTRICITY TRANSMISSION COST ALLOCATION 1 (2012).
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further spurring costs. The Department of Energy (DOE)’s national goal of “twenty percent wind by 2030” carries estimated transmission expansion costs of $60 billion. Generating 80 percent of our nation’s energy from renewable sources by 2050 would necessitate almost doubling existing transmission lines. A study sponsored by Michigan utilities, for instance, found that spreading wind transmission costs across the state’s ratepayers would result in them subsidizing no less than 20 percent of $16 billion in transmission projects outside the state.

The question of who pays also matters because under the Federal Power Act (FPA), the costs of interstate transmission must be allocated to ratepayers—be they utilities buying wholesale electricity from the grid or energy customers paying their bills—in a “just and reasonable” manner. In interpreting the statute, courts have established the principle of “cost causation”: interstate electricity rates must “reflect to some degree the costs actually caused by the customer who must pay them.” Courts thus compare “the costs assessed against a party to the burdens imposed or benefits drawn by that party.” The two must be at least roughly commensurate.

Application of this principle stands at the center of transmission cost allocation litigation.


22. Illinois I, 576 F.3d at 476.

23. Id.

24. Id. at 477.

In *Illinois Commerce Commission v. FERC*, the Seventh Circuit upheld a transmission financing plan that spreads—i.e. socializes—the costs of certain renewables transmission projects (multi-value projects or “MVPs,” which transmit wind power) across the member-utilities of the Midwest Independent System Operator (MISO). Specifically, the court endorsed FERC’s certification of MISO’s cost allocation according to a load-ratio share tariff. Under this tariff, each member-utility will pay MVP costs proportional to its respective electricity draw from the MISO grid as MVP construction advances. The tariff permissibly spreads these costs across the entire member-utility pool because the projected grid-wide, MVP-secured benefits are sufficiently commensurate with per-utility tariff costs.

Assuming the tariff plan proceeds smoothly, the chicken-or-the-egg dilemma that often thwarts renewables investment—which comes first, the renewables or the transmission to carry their power to market?—will not afflict MISO. Renewables advocates heralded the ruling as an important step toward favorable and predictable financing for wind energy. Wind investors may now enjoy costs of transmission spread broadly—easing their ability to site in the remote locations with the best wind and increasing their certainty that the generated energy will reach consumers.

The *Illinois Commerce* holding represents a step forward in renewables-to-grid integration, but renewables advocates should not overly celebrate. While the Supreme Court did not grant certiorari to objecting state and utility parties, the Seventh Circuit has not created a sweeping rationale for socialized tariff structures, since the benefits cited by the court as satisfying cost causation and their per-utility distribution are RTO-specific and subject to inherent limitations of future incalculability. Such incalculability renders them to some degree uncertain, and FERC and RTOs may therefore face a sizeable hurdle in the critical endeavor of planning the transmission necessary to smoothly integrate distance-transmitted renewables into RTOs.

Finally, if renewables-to-grid integration is to proceed unencumbered by ongoing, large-scale litigation, FERC or Congress should clarify three areas of ambiguity in cost allocation: (1) the definition of “benefits” under Order 1000, (2) the necessary granularity of transmission cost/benefit analyses, and (3) the frequency of benefit-to-cost reporting on completed transmission projects. Clarification in these areas will assist FERC and courts in determining when transmission tariff plans comply with the cost causation principle, and when

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27. *Id.*
28. *Id.*
transmission organizations may permissibly socialize transmission costs. Such determination will, in turn, secure faster construction of urgently needed transmission.

I. BACKGROUND

A. Transmission Benefits: A Brief Overview

When one pays the electricity bill each month, what does it cover? The amount billed represents the costs associated with the four “phases” of grid functionality—generation, transmission, distribution, and ancillary services such as grid maintenance and administration—all on a monthly basis. Transmission-related costs currently constitute about 8 to 10 percent of a utility bill. While a small portion of each individual’s bill, these costs cumulatively represent a large sum. Since the successful integration of renewables depends upon a national grid that is robust, reliable, and efficient—goals often necessitating transmission construction—these costs are likely on the rise.

Transmission is the link between generation and distribution. Generation comprises the creation of electricity from nonrenewable sources, including coal, gas, nuclear, and renewable sources, including wind, solar, biomass, and hydro. The transmission phase includes network transmission facilities, generally consisting of lines and equipment for transmitting power in excess of 100 kilovolts; local distribution facilities, consisting of lines and equipment for delivering electricity directly to end users; and interconnection facilities, linking generation to network transmission facilities. As used in this Note, “transmission” refers to network transmission facilities. These facilities generate the bulk of transmission costs and most cost allocation contention.

Four distinct transmission grids—or “interconnections”—cover much of North America, crossing municipal, state, and national boundaries. These are the Eastern Interconnection, covering most the United States and Canada east of the Rock Mountains; the Western Interconnection, covering the United States and Canada west of the Rockies; the Electric Reliability Council of Texas, covering most of Texas; and the Quebec transmission system in Canada. Each interconnection contains subgrids that vary in geographic size


33. PJM INTERCONNECTION, supra note 2, at 5–6.

34. Id.

35. Id.
from single cities to multiple states, remain connected to the parent interconnection, and are themselves highly complex systems. Independent System Operators (ISOs) and RTOs, like MISO, are common types of subsystems and serve two-thirds of the U.S. population. MISO alone serves a population of approximately 40 million and has 50,235 total miles of transmission lines.

The quality of the transmission system has a material impact on costs to consumers. During transmission, a portion of the electrical flow is lost between origination and destination. Transmission lines may also become congested when transmitting power levels exceeding line capacity. Congestion produces service disruptions and system damage, and requires redispach of generators—all costly. As solutions, grid planners often employ high-voltage lines, which dramatically reduce loss, making them commonly chosen for long-distance transmission. Such lines also eliminate congestion that might otherwise exist with similar power levels moving on low-voltage lines. High-voltage transmission is generally required if siting of distance-transmitted renewables is to be ideal. Most U.S. grid expansion involves—significantly or predominately—the construction of high-voltage transmission.

Through such construction, grid planners generally hope to enjoy a lasting buffet of benefits, each distinct and some not easily quantifiable. These benefits include enhanced grid reliability through, among various means, lowered losses and congestion; economic benefits, including increased efficiency, increased system capacities, lowered losses and congestion, and better transmission tailoring to fluctuations of energy market prices; grid modernization through upgrade and/or line repair; expansion of the grid to new generation sources, utilities, and customer pools, often satisfying public policy requirements and increasing fuel diversity, which mitigates generation price volatility; and combinations of some or all of these.

The determination of who precisely benefits from a specific transmission project remains a realm of ambiguity and policy discord. Transmission benefits accrue predominately to two groups: electricity generators, and power customers and end-users, referred to as “load.” Power flow models reveal those transmission users—generators, load, or both—that affect power flows upon a given project. Such flow “causers” present one definition of beneficiaries: those that use a given transmission project and thus “cause” the necessity of its construction cost. There are additional project benefits, however, beyond those

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36. *Id. at 4.*
37. *Id. at 5; see infra Part II.B.*
38. *PJM INTERCONNECTION, supra note 2, at 5.*
39. *Id. at 6.* As used in this Note, “grid planners” refers to ISO and RTO officials.
40. *Id.*
41. *Id.*
42. *Id.*
43. *Id. at 18–19.*
44. *Id. at 18.*
accruing to flow causers.\textsuperscript{45} Such benefits are grid-wide and include enhanced reliability and decreased price variation in the energy market.\textsuperscript{46} Power flow modeling and market simulation fail to predict the extent of these benefits.\textsuperscript{47} As a remedy, grid-planners employ a broader definition of beneficiary, established through quantifying series of transmission-impacted variables before the proposed construction, and comparing them to predicted post-construction series.\textsuperscript{48} Those parties shown to derive monetary benefit from the variables are the project beneficiaries.

In the face of climate change and advancing renewables investment, commentators highlight the failure of beneficiary definitions to quantify—or even include—positive externalities resulting from the contribution of transmission construction toward public policy goals. Commenting during FERC rulemaking prior to Order 1000 on attempts to define beneficiaries, the RTO Southwest Power Pool stated, “The real benefits of a major transmission project . . . over its useful life will never be fully captured in an economic model as there are many benefits that fall outside the scope of economic modeling. While precise analysis may be desirable, the limitations of such analysis must be acknowledged.”\textsuperscript{49} Traditional transmission beneficiary identification breaks down when transmission projects allow the incorporation of new fuel sources that reduce carbon emissions. This, in turn, reduces U.S. dependence on foreign energy sources, secures reliability-enhancing fuel diversity, and secures reliability beyond the immediate grid.\textsuperscript{50} Externality beneficiaries may have had no say in transmission planning, will likely never use the expanded transmission, and do not belong to the grid’s customer pool—yet they derive cognizable benefits nonetheless. Certain RTO planning processes, including MISO’s, now allow stakeholders to include positive externality criteria in transmission planning.\textsuperscript{51} Courts, including the Seventh Circuit, and FERC may now grapple with the degree to which positive externalities produced by public policy fulfillment may enter beneficiary definitions for cost allocation.

\textsuperscript{45} ld. at 19.
\textsuperscript{46} ld.
\textsuperscript{47} ld.
\textsuperscript{48} ld. Quantified variables include wholesale energy prices, energy capacity market price changes, customer expenditures on electricity, and utility and generator revenues. ld.
\textsuperscript{49} FED. ENERGY REGULATORY COMM’N, COMMENTS OF SOUTHWESTERN POWER POOL, INC., REGARDING TRANSMISSION PLANNING PROCESSES UNDER ORDER NO. 890, at 12 (2009).
\textsuperscript{50} PJM INTERCONNECTION, supra note 2, at 22. Additional positive externalities from transmission construction include job creation and facilitation of business/industry expansion. ld.
\textsuperscript{51} ld. (“The Midwest ISO leaves open the possibility for stakeholders to add criteria such as public policy objectives, economic development benefits, and national security considerations.”); see Klass &Wilson, supra note 7, at 1870–71 (“Building upon prior efforts by regions such as PJM to expand cost allocation across regional participants, MISO’s MVP plan recognizes that benefits accrue not just due to reliability and economic impacts, but also due to the achievement of various state and regional policy goals and mandates such as RPSs.”).
B. Statutory Background: FERC and the Federal Power Act

As an independent regulatory commission within the DOE, FERC is the federal agency charged with reviewing interstate transmission cost allocation schemes. FERC derives this regulatory authority primarily from the FPA.\textsuperscript{52} Broadly, FERC’s regulatory domain includes the transmission of electricity in interstate commerce,\textsuperscript{53} including rates and conditions, and any public utilities generating or purchasing interstate.\textsuperscript{54} FERC regulates proactively through rulemaking and passively through reviewing ratemaking and other actions by utilities and other grid actors.\textsuperscript{55} FPA sections 205 and 206 establish FERC’s jurisdiction over RTOs and sets the standard for transmission.\textsuperscript{56} Under section 205, utilities or grid planners may seek FERC approval to change their electricity rates, transmission tariffs, or related charge terms.\textsuperscript{57} A tariff and its cost allocation require timely submission to FERC, which applies section 205’s “just and reasonable” review standard.\textsuperscript{58} FERC accepts, rejects, or modifies the filing on this basis.\textsuperscript{59}

Unlike section 205, section 206 places FERC in a proactive role with prospective authority to set those rates found “unjust and unreasonable.”\textsuperscript{60} FERC may initiate investigation of rates on its own or upon suggestion of power customers or other impacted parties.\textsuperscript{61} Such rates would have first

\textsuperscript{52} See 16 U.S.C. § 824d(a), (d) (2012); JAMES H. MCGREW, FEDERAL ENERGY REGULATORY COMMISSION: BASIC PRACTICE SERIES 20–21 (2d ed. 2009). Courts’ interpretation of section 824d(a) has produced the cost causation principle, discussed below. Subsection (a) provides:

All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.


\textsuperscript{53} Pursuant to Federal Power Commission v. Florida Power & Light Co., 404 U.S. 453, 461 (1972), “interstate” under the FPA includes circumstances where the contractual origin and destination of transmission occur within the same state, if the transmission is within the continental United States, with the exception of most of Texas. “Interstate” applies to same-state transmission because of the interconnectedness of the national transmission system, which ensures the mix of electrons from different states, even within single states.

\textsuperscript{54} See MCGREW, supra note 52, at 20–22; 16 U.S.C. § 824d(d); Wayne Galli et al., Electric Transmission 101: How the High-Voltage Grid Works and Who Regulates It (Envtl. & Energy Study Inst. Speaker Presentation, July 9, 2013) (audio recording available at http://www.eesi.org/electric-transmission-101-how-high-voltage-grid-works-and who-regulates-it-07-apr-2011). Further realms of FERC jurisdiction include the intrastate wholesale of electricity for subsequent resale in interstate commerce and transmission project siting under limited instances. Id. Conversely, state regulatory authority governs retail electricity sales (generally to end users); most low-voltage transmission; siting of generation and transmission lines; and generation sources available to utilities as stipulated by RPSs or other laws. Id.

\textsuperscript{55} See MCGREW, supra note 52, at 21–22, 176.

\textsuperscript{56} See 16 U.S.C. § 824d(d), (e).

\textsuperscript{57} Id.; see MCGREW, supra note 52, at 176.

\textsuperscript{58} 16 U.S.C. § 824d; see MCGREW, supra note 52, at 21, 176.

\textsuperscript{59} 16 U.S.C. § 824d.

\textsuperscript{60} Id. § 824e.

\textsuperscript{61} Id.; see MCGREW, supra note 52, at 22, 176.
received FERC approval, but subsequently lapsed into violation.\textsuperscript{62} Last, section 206 empowers FERC to set a just and reasonable rule, regulation, or practice “to be thereafter observed and in force,” and to “fix the same by order.”\textsuperscript{63}

II. THE EMERGENCE OF MODERN TRANSMISSION COST ALLOCATION

A. The Bundled Grid

As a result of FERC rulemaking, renewables now enter electricity grids that are “unbundled.”\textsuperscript{64} Unbundling has irrevocably sculpted the grid, increasing competition among utilities, generators, and transmission suppliers. Broadly, unbundling provided renewables generators greater access to existing transmission infrastructure, and thus customers,\textsuperscript{65} who, in turn, gained a larger selection of energy suppliers. Unbundling has also contributed to the complexity surrounding “just and reasonable” ratemaking.\textsuperscript{66}

At the time of FPA passage in 1935, utilities were vertically integrated monopolies selling bundled services.\textsuperscript{67} Until the 1990s, a single utility generally provided generation, transmission, distribution, and upkeep services for its franchised service territory.\textsuperscript{68} Generation and transmission generally existed near or within the service territory, providing the controlling utility a localized operation.\textsuperscript{69} Utilities stated a single rate encompassing these services, and customers paid a single price for them—the bundle.\textsuperscript{70} Customers were “captive” to the bundle. If they sought cheaper or differing generation sources, distribution, or grid maintenance, they could not step out of the utility’s territory to other providers of the desired service. Utilities enforced customer captivity by charging discriminatory rates to any outside generator seeking transmission on the utility’s infrastructure, or by denying access altogether. Discriminatory rates meant that competitors could deliver electricity to captive consumers only at rates higher than the transmission-owning utility. The

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\item FERC bears the burden of proving first that the rates violated cost causation, and, second, that its new rates would satisfy the principle. The Commission may order refunds to customers for a limited period, covering the unreasonable rates. \textit{Id.}; see 16 U.S.C. § 824e(a), (b).
\item 16 U.S.C. § 824e.
\item See infra Part III.B; McGrew, supra note 52, at 154.
\item See KEVIN PORTER, NAT’L RENEWABLE ENERGY LAB., OPEN ACCESS TRANSMISSION AND RENEWABLE ENERGY TECHNOLOGIES 4 (1996).
\item CAMPBELL & VANN, supra note 16, at 4.
\item McGrew, supra note 52, at 151.
\item CAMPBELL & VANN, supra note 16, at 4.
\item See McGrew, supra note 52, at 151.
\item Midwest ISO Transmission Owners v. Fed. Energy Regulatory Comm’n, 373 F.3d 1361, 1363 (D.C. Cir. 2004) (discussing the history of vertically integrated utilities). Transmission technology advances eventually allowed utilities to locate generation at greater distance from customers, and to connect transmission lines with adjacent utilities. Such connections allowed utilities to discern the economic and reliability benefits of selling power to each other. Even such sales—the wholesale power market—entailed bundling generation with the necessary corresponding service, such as transmission to the purchasing utility. See CAMPBELL & VANN, supra note 16, at 4.
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Supreme Court observed that during this period, “[c]ompetition among utilities was not prevalent.”

Importantly, utilities allocated the costs of new transmission projects to their captive load ratepayers. Load generally paid transmission costs; generators under the utility’s control did not. Since utilities enjoyed control over their territories, the project benefits did not accrue to outside parties. Transmission cost allocation was relatively noncontentious.

## B. The Unbundled Grid

Invoking its authority under sections 205 and 206 of the FPA, FERC issued Order 888 in 1996 to unbundle utilities’ services.

FERC viewed “market power through control of transmission [as] the single greatest impediment to competition” in wholesale power markets.

Order 888 required transmission-owning utilities to guarantee nondiscriminatory grid access to all participants in the interstate electricity market. Each utility was to state separate rates for generation, transmission, and ancillary services, and to place transmission of wholesale power under a “single general tariff applicable equally to itself and to others.”

Outside generators would thus receive transmission on the terms transmission-owning utilities provided their own generators.

The order also encouraged, but did not mandate, the formation of multi-utility RTOs. FERC feared that even if unbundled, individual utilities would create a patchwork transmission grid over large areas. Such a grid would impede long-distance transmission and deny consumers access to generator

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72. See PJM INTERCONNECTION, supra note 2, at 23.
73. ROSS BALDICK ET AL., BLUE RIBBON PANEL ON COST ALLOCATION, A NATIONAL PERSPECTIVE ON ALLOCATING THE COSTS OF NEW TRANSMISSION: INVESTMENT: PRACTICE AND PRINCIPLES 32 n.34 (2007), available at http://www.wiresgroup.com/images/Blue_Ribbon_Panel_-_Final_Report.pdf (“Where in the past the issue was simply ‘swept under the rug,’ today the issue is a more transparent one.”).
77. See Order No. 888, 61 Fed. Reg. at 21,541.
diversity.\textsuperscript{80} With RTOs, utilities would retain ownership of their respective transmission facilities, while the RTO would serve as an oversight organization, coordinating inter-utility power sales and preventing anticompetitive practices.\textsuperscript{81} Single, interconnected multi-utility transmission grids would emerge.

Customers gained access to power sources well outside their immediate utility’s chosen generation sources and geographic location. Such power sources included renewables.\textsuperscript{82} Remote renewables generators gained the ability to target the most favorable markets, regardless of their location, rather than having to rely on those utilities that decided to provide transmission access.\textsuperscript{83} While consumer access to renewables depended on myriad factors including state public policy, renewables-friendly geography, and renewable energy prices, the transmission securing access now came at a foreseeable, nondiscriminatory rate.

Unbundling services blurred the links between parties that planned, built, operated, and benefited from new transmission.\textsuperscript{84} Utilities traditionally recovered transmission costs from their captive loads and investors, subject to cost-of-service regulation by state utility commissions.\textsuperscript{85} New transmission would primarily benefit the transmission-building utility’s service territory. With generation and transmission unbundled, transmission construction could benefit not only the service territory but also outside generators, utilities, and customers, all paying the nondiscriminatory tariff to access that building utility’s facilities. Varied transmission benefits might accrue in differing levels to any party, inside or outside the utility’s zone. In RTO-administered regions, large trans-utility projects could provide both localized and regional benefits.\textsuperscript{86}

In 2000, concerned with potential lingering market inefficiencies and

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\item \textsuperscript{80} Id. at 21,734; see also Midwest ISO Transmission Owners v. Fed. Energy Regulatory Comm’n, 373 F.3d 1361, 1364 (D.C. Cir. 2004).
\item \textsuperscript{81} Order 889 functioned in tandem with Order 888 to address remaining potentially anticompetitive practices, and to require the provision of transmission pricing information to outside generators. The Order required separation of utilities’ transmission employees from transmission-sales employees. FERC sought to prevent sales employees from gaining “inside track” information from their transmission counterparts, facilitating discrimination against outside generators. Further, the Order required utilities’ transmission operators to establish the Open Access Same-Time Information System, providing transparent and accurate transmission information to outside generators wishing to purchase facilities access. Such information would ensure non-discriminatory access to the utilities’ lines and consumers; see McGrew, supra note 52, at 154.
\item \textsuperscript{82} See Porter, supra note 65, at 4–5.
\item \textsuperscript{83} Id.
\item \textsuperscript{84} See Campbell & Vann, supra note 16, at 4–5.
\item \textsuperscript{85} Id.
\item \textsuperscript{86} For example, transmission projects to increase grid reliability might benefit all parties using the grid, whereas a single project to increase transmission efficiency might predominantly benefit a single utility’s customers, or only certain of the utility’s customers, compared to other parties. Moreover, a single project might provide both reliability benefits to all, and economic benefits to isolated parties. Determining which benefits a project would produce—and to whom they would accrue, and in what quantity—became a point of increasing ambiguity and contention among grid planners, utilities, and electricity customers.
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discriminatory practices, FERC issued Order 2000.\textsuperscript{87} The order directed transmission-owning utilities either to join an RTO or to explain their refusal to do so. It also required that RTOs hold exclusive and independent authority to propose rate changes for transmission costs within the RTO region.\textsuperscript{88} RTOs could have no financial interest in any market participants.\textsuperscript{89} In essence, RTOs were to be nonprofit, with voluntary utility membership. The RTO would exercise utility-ceded operational control over transmission, informed by FERC’s prior orders addressing discriminatory utility practices.

Under these parameters, FERC established basic areas of RTO responsibility, including short-term grid reliability, electricity congestion management, grid upkeep and grid expansion.\textsuperscript{90} Each of those areas implicates transmission project planning and cost allocation decisions made by the RTO through its unique governance process. After Order 2000, RTOs oversee approximately two-thirds of U.S. electricity.\textsuperscript{91}

\textbf{C. Cost Allocation Challenges and FERC’s Responses: Orders 890 and 1000}

RTOs generally allocate transmission costs just to load rather than to both load and generators.\textsuperscript{92} Critics argue that because certain generators—commonly wind—depend on transmission expansion in order to reach customers, they should bear transmission costs along with load. While various RTOs, including MISO, are making tentative and limited use of such allocation, load continues to bear most or all transmission costs.\textsuperscript{93}

RTOs commonly employ two broad cost allocation frameworks. The first is a “postage stamp” rate plan, under which each transmission customer pays a single rate for any transmission transaction within a defined, multi-utility RTO region regardless of the contractual origin and contractual destination of the

\textsuperscript{87} See Regional Transmission Organizations, Order No. 2000, 18 C.F.R. § 35.34 (2014); \textit{Fed. Energy Regulatory Comm’n, Regional Transmission Organizations} 2 (1999), available at https://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf ("[T]he Commission reviewed evidence that traditional management of the transmission grid by vertically integrated electric utilities was inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets, and that continued discrimination in the provision of transmission services by vertically integrated utilities may also be impeding fully competitive electricity markets."). Broader questions of RTO governance, structure, and accountability are beyond the scope of this Note.

\textsuperscript{88} 18 C.F.R. § 35.34(j)(1)(iii).

\textsuperscript{89} Id. § 35.34(j)(1)(i). Further, FERC required that each RTO be regional in scope, have operational authority for all transmission facilities under its control, be the only provider of transmission service over lines under its control, and have sole authority to receive, evaluate, and approve or deny all requests for transmission service. RTOs did not gain ownership over transmission assets; ownership remained with the utilities. Id.

\textsuperscript{90} Id. § 35.34(k)(1), (7)(i)(ii).

\textsuperscript{91} See ISO/RTO Council, \textit{Progress of Organized Wholesale Electricity Markets in North America} 1 (2007) ("Two-thirds of the United States . . . is supplied wholesale electricity through markets run by ISOs or RTOs.").

\textsuperscript{92} See PJM Interconnection, supra note 2, at 23–24.

\textsuperscript{93} Id.
electricity transmitted.\textsuperscript{94} Transmission costs over a time period—or at a single point in time, such as system peak—are divided by total units transmitted, resulting in an average cost per unit, allocated uniformly across all the region’s ratepayers.\textsuperscript{95} A customer may occupy territory through which the funded transmission only passes, but will pay the same average rate, regardless of the transmission benefit derived or cost caused by the customer. After individualized assessment of anticipated costs and benefits, such customers and their utilities might object to a postage stamp rate, arguing it shifts costs in violation of the cost causation principle. Such assessment may find that a paying customer’s transmission needs do not require the funded transmission. The customer is therefore not “causing” its cost. However, when transmission projects bring sufficient positive externalities, postage stamp rates may lessen or eliminate freeriding by spreading costs broadly.

The second is a “license plate” rate—also illustratively termed “zonal” rates—under which each customer’s cost allocation reflects the cost of projects only within the customer’s service territory (“zone”), generally demarcated by the utility to which the customer belongs.\textsuperscript{96} When projects pass through multiple service territories, customers in those zones receiving substantial benefit still pay only their zone’s established transmission rate. A customer in a high-transmission-cost territory therefore might pay more than a customer in a low-cost territory.\textsuperscript{97} Such a cost allocation plan might employ a license plate rate to fund a majority of the costs, while allocating remaining costs across zones through a postage stamp rate.

FERC has recognized that in some instances zonal rates prevent transmission cost shifting from utilities with higher transmission costs to those with lower.\textsuperscript{98} Substantial cost shifting through frequent postage-stamp-funded projects could encourage utilities with below-average transmission costs and needs to leave or refuse to join RTOs, hampering necessarily regional transmission planning and destabilizing the RTO.\textsuperscript{99} Without producing clear system-wide benefits commensurate with individually borne costs, postage-stamp-funded projects draw the ire of repeated litigation as utilities seek to ensure they do not pay for transmission that does not commensurately benefit them.

FERC issued Order 890 in 2007, cognizant of transmission needs not


\textsuperscript{95} Id.; PJM Interconnection, supra note 2, at 47.

\textsuperscript{96} Hempling, supra note 94, at 2.

\textsuperscript{97} Id.

\textsuperscript{98} See PJM Interconnection, L.L.C., Opinion No. 494, 119 FERC ¶ 61,063, 61,370 (April 19, 2007) (“[W]e cannot ignore the effects that cost shifts can have on RTO participation. Substantial shifts in cost responsibility could encourage a utility with below-average transmission costs to remain independent of or leave an RTO and, as a result, might destabilize an RTO.”).

\textsuperscript{99} See id.
funded through standard rate structures such as postage stamp and license plate rates. Projects not covered by existing rate structures often include large-scale projects with regional rather than localized benefits, crossing multiple rate zones and state boundaries. Covered projects generally include those needed by single service area—charged to the customers of that zone. As FERC observed, “transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs.”101

In the order, FERC established nine planning principles for RTOs to address, including cost allocation for new facilities not covered by existing rate structures.102 FERC did not prescribe a set cost allocation methodology.103 Instead, FERC prescribed three factors for RTOs to weigh in determining the permissibility of a given cost allocation plan. Under the order, the proposed allocation should fairly assign costs among participants, including those who cause them to be incurred and those who otherwise benefit from them; provide adequate incentives to construct new transmission; and be generally supported by state authorities and participants across the region.104 The Commission stressed the need for “ex ante certainty through definite cost allocation rules and clear rules for identifying who benefits from specific projects.”105 For postage stamp rate plans that fund transmission across more than one utility, the Commission urged planners to consider recent precedent to determine plan permissibility.106

Pursuant to Order 890, RTOs have planned transmission cost allocation in varying manners. In the New England ISO—an RTO covering the states of Maine, Vermont, New Hampshire, Massachusetts, Connecticut, and Rhode Island—transmission projects producing grid-wide reliability benefits received RTO-wide cost allocation through postage stamp plans. Between 2004 and December of 2012, the costs of the projects had totaled approximately $4 billion.107 Some point to New England ISO as illustrative of the greater ease with which reliability project costs can be socialized.108 A single failure in the regional grid would conceivably impact all ratepayers, justifying their burden

100. Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266, 12,336 (Mar. 15, 2007) (codified at 18 C.F.R. pts. 35, 37) (“The cost allocation principle discussed herein is intended to apply to projects that do not fit under the existing structure, such as regional projects involving several transmission owners.”).
101. Id. at 12,335–36.
102. Id.
103. Id. Revealingly, the agency elaborated that cost allocation was “not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.” Id. at 12,336 (quoting Colo. Interstate Gas Co. v. Fed. Power Comm’n, 324 U.S. 581, 589 (1945)).
104. Id. at 12,336.
106. Id.
108. Id.
in projects that eliminate such possibilities. Conversely, a single project to secure economic benefits might only benefit certain customers, weighing against regional cost socialization.

D. The Seventh Circuit Clarifies the Cost Causation Principle for High Voltage Transmission Delivering Grid-Wide Reliability Benefits

In 2009, in Illinois Commerce Commission v. FERC (Illinois I), the Seventh Circuit rejected PJM Interconnection’s FERC-approved cost allocation plan for new transmission facilities carrying 500 kilovolts or more. As an RTO, PJM sought to socialize new transmission costs through a postage stamp plan for all utilities within its territory. Previously, PJM had allocated transmission project costs according to utility-by-utility calculations of the benefits derived from each project, heeding Order 890 and cost causation precedent. The plan for the 500-kilovolts projects presented a departure from traditional granularity yet still sought to adhere to cost causation and FERC’s orders.

Unique geographic proximity among PJM utilities posed a challenge to FERC in meeting its cost causation burden. Utilities in the western PJM territory are closer to power plants and each other, allowing for cheaper, low-voltage lines to fulfill most transmission needs. Utilities in the eastern portion are further apart, requiring higher voltage lines to transmit over longer distances. The western utilities believed they would derive less-than-average benefits compared to their eastern colleagues yet still pay the cost-averaged postage stamp rate.

FERC argued that PJM’s plan satisfied the cost causation principle on two grounds. First, FERC argued that eastern PJM utilities had employed similar cost socialization in the past. The court held, however, that past practices were insufficient to justify the plan. Second, FERC asserted that benefits of the projects were too difficult to measure precisely and therefore would likely entail an unreasonable amount of litigation. Given the interconnected nature of the grid, the projects nonetheless created undeniable reliability benefits for all utilities. The court recognized the PJM plan’s reliability benefits, but chided FERC for providing nothing to allow even the roughest of “ballpark

109. Id.
110. Id.
111. Illinois I, 576 F.3d at 478.
112. Id. at 474.
113. Id.
114. Id.
115. Id. at 475.
116. Id.
117. Id.
118. Id.
119. Id.
120. Id. at 476.
estimates” of them.\textsuperscript{121} FERC had not provided any quantification.\textsuperscript{122}

In Illinois I, FERC presented neither measurable benefits, nor an explanation of their absence coupled with an articulable and plausible reason for the benefits still matching costs. Thus the plan failed. While FERC may presume new transmission lines provide reliability benefits to the entire grid under Illinois I, it may not use this presumption alone to fulfill its statutory duty of “comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.”\textsuperscript{123} The Commission need not calculate benefits “to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars.”\textsuperscript{124} It must provide some measure of benefits, however, with leeway in precision, when asserting grid-wide reliability as sufficient for cost socialization. If such measure is not possible, FERC must provide an explanation of why and an “articulable and plausible” reason to believe that the benefits are at least “roughly commensurate” is sufficient for the Commission to satisfy cost causation.\textsuperscript{125}

\subsection*{E. Transmission Cost Allocation Parameters Before Illinois II}

After the Seventh Circuit’s rejection of PJM’s cost socialization in Illinois I, congressional attempts to provide guidance in transmission cost allocation,\textsuperscript{126} and various newly passed state RPS requirements, FERC issued Order 1000 in 2011.\textsuperscript{127} The order requires public utilities to participate in a regional transmission planning process that “consider[s]”\textsuperscript{128} transmission needs created by “public policy requirements,” including state RPSs.\textsuperscript{129} Importantly, the order also permits incorporation of “transmission needs driven by additional public policy objectives not specifically required by state or federal laws or regulations.”\textsuperscript{130} Thus RTOs may employ an expansive view in determining

\begin{itemize}
\item \textsuperscript{121} Id.
\item \textsuperscript{122} Id. at 477.
\item \textsuperscript{123} Id.
\item \textsuperscript{124} Id.
\item \textsuperscript{125} Id.
\item \textsuperscript{126} See S. 400, 112th Cong. § 1 (2011) (not enacted); American Clean Energy Leadership Act of 2009, S. 1462, 111th Cong. § 121 (2009) (not enacted); see also supra note 12.
\item \textsuperscript{128} Order No. 1000, 76 Fed. Reg. at 49,878–79. By “consider,” FERC has stipulated that RTOs and utilities must both “identify” transmission needs driven by public policy requirements and “evaluate” potential solutions to meet those needs. Id. at 49,878.
\item \textsuperscript{129} Id. at ¶ 214. In a May 2012 Rehearing and Clarification, FERC defined “public policy requirements” as “state or federal laws or regulations that drive transmission needs.” See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000-A, 77 Fed. Reg. 32,184, 139 FERC ¶ 61,132 (May 31, 2012) (order on rehearing and clarification).
\item \textsuperscript{130} Order No. 1000, 76 Fed. Reg. at 49,878–79.
\end{itemize}
which policies should inform transmission planning. Such requirements likely create high potential that renewables will play an established role in future RTO transmission planning.

On its face, the cost causation principle is unremarkable. Courts compare the costs assessed against a party to the burdens imposed or benefits drawn by that party. The two must be roughly commensurate. FERC is not required to “reject any rate mechanism that tracks the cost causation principle less than perfectly.” It is enough under the Administrative Procedure Act’s standard of review “that the cost allocation mechanism not be ‘arbitrary or capricious’ in light of the burdens imposed or benefits received.”

As Gabe Maser outlines in “It’s Electric,” three scenarios allow either greater leeway in matching benefits to costs or cost socialization without individualized cost-to-benefit analysis. The first is when such analysis is both infeasible and subject to “unending controversy,” permitting FERC to assert less particularized benefits for weighing against the project costs. Infeasibility, as elaborated by the Seventh Circuit, requires a defined showing that the benefits in question cannot be calculated with the particularity available in other instances. An “unending controversy” requires FERC to show an approximate estimate of the amount of litigation it expects the granulated benefits analysis to produce.

The second scenario, identified by the D.C. Circuit in Midwest ISO Transmission Owners v. FERC, is when cost causation permits an RTO to socialize its administrative costs without an individualized benefits-to-costs analysis. The court views such costs as essential to the function of the RTO,


132. Some have questioned whether FERC’s “consider” is sufficient imperative to bring renewables-motivated projects to construction. See Welton & Gerrard, supra note 131. FERC established six principles to assure that cost allocation decisions better matched the cost causation principle. Campbell & Vann, supra note 16, at 16. The order broadly affirms that there may be no cost allocation where there is no derived benefit. Id. In each principle, FERC distinguishes between regional and interregional transmission projects, seemingly anticipating the interregional nature of projects crossing long distances to transmit renewables, or expand RTOs. Id. Notably, FERC refrains from defining “benefit” produced by transmission projects, leaving the term open to encompass the varied benefits supplied by transmission projects. Id. at 19.

133. Illinois II, 721 F.3d at 770.

134. Id.


137. See Maser, supra note 11, at 1838.

138. Illinois I, 576 F.3d at 475 (quoting Sithe, 285 F.3d at 5).

139. Id. at 475–76; see also Maser, supra note 11, at 1838.

140. Illinois I, 576 F.3d at 475–76.

141. See Maser, supra note 11, at 1838; Midwest ISO Transmission Owners, 373 F.3d at 1372 (approving FERC’s approval of a tariff allocated to all users of the MISO grid according to their respective transmission volumes).
in turn benefitting all member utilities through grid reliability, reduction in transmission cost and inefficiency, and large-scale regional coordination and transmission planning.\textsuperscript{142} While certain utilities might not continuously use or need all benefits afforded by the RTO, they nonetheless benefited from the RTO’s existence and the benefits’ availability.\textsuperscript{143} The third, identified by the D.C. Circuit, is when transmission construction that enhances reliability on an integrated grid benefits all users, permitting cost socialization. Under such a scenario, FERC is not required to produce individualized benefits analysis.\textsuperscript{144} As the Seventh Circuit held when scrutinizing cost socialization in \textit{Illinois I}, FERC may not merely assert that such benefits accrue to all members to justify socialization.\textsuperscript{145} FERC’s Seventh Circuit burden is the presentation of “ballpark” quantified figures of benefits as matching costs, or an explanation of the absence of such a figure with an “articulable and plausible reason” to believe that the benefits are still “at least roughly commensurate” with the costs.\textsuperscript{146}

\section{I\textsc{llinois} Commerce (2013): MISO’s Break with Tradition}

\textbf{A. MISO’s MVP Portfolio Process}

On December 16, 2010, FERC approved MISO’s revised tariff funding a new transmission project category, “MVPs,” intended to transmit power from various upper Midwestern-state wind farms to interconnections with the MISO grid.\textsuperscript{147} MVP selection arose through a three-year stakeholder-RTO meeting process.\textsuperscript{148} To qualify as an MVP, a transmission project must fulfill at least one of three conditions: be developed for the purpose of enabling [MISO] to reliably and economically deliver energy in support of documented energy policy mandates or laws . . . [and] be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would

\begin{itemize}
\item \textsuperscript{142} See \textit{Midwest ISO Transmission Owners}, 373 F.3d at 1372. MISO RTO administrative costs included grid security, administrative capital, and administration of tariffs, as well as scheduling, system control, and dispatch services. \textit{Id}.
\item \textsuperscript{143} \textit{Id}.
\item \textsuperscript{145} \textit{Illinois I}, 576 F.3d at 477.
\item \textsuperscript{146} \textit{Id.} at 476–78.
\item \textsuperscript{147} \textit{Midwest Indep. Transmission Sys. Operator, Inc. (MVP Order)}, 133 FERC ¶ 61,221 (2010), \textit{order on reh’g}, 137 FERC ¶ 61,074 (2011).
\end{itemize}
be without the . . . upgrade;

provide “multiple types of economic value across multiple pricing zones with a total MVP Benefit-to-Cost [R]atio of 1.0 or higher”; or address “at least one Transmission Issue associated with a projected violation of reliability standards” and “at least one economic-based Transmission Issue that provides economic value across multiple pricing zones.”149 The final portfolio contained seventeen MVPs, ranging in cost from $26 million to $714 million.150 In total, the portfolio came to over $5 billion.151

MISO traditionally allocated low voltage and most high voltage transmission costs subregionally according to geographic proximity.152 Such allocation proceeded on the theory that those utilities closest predominately derived the benefits of the projects,153 and presented apparent “one-to-one” correspondence between the causers of the costs and those utilities allocated them. By contrast, when ideally sited, MISO wind farms produce power in excess of the demands of the nearest utilities and markets.154 Traditionally, these parties would singlehandedly cover the costs of the transmission from proximate farm to grid-interconnection. Yet such utilities do not, by any standard, drive the costs of wind transmission, given their comparatively lower power needs. Further, the benefits of additional power would likely accrue to parties well beyond them. Many wind-proximate utilities either could not pay or refused to pay the necessary costs.155 MISO therefore decided to pursue new cost allocation, the MVP tariff.156

In Illinois II, the Seventh Circuit upheld FERC’s approval of the tariff,157 which allocates MVP costs to each MISO-member utility proportional to its total draw of electricity from the MISO grid. Similar to a postage stamp plan, all member utilities bear the cost but in proportion to their load ratio share rather than a grid-wide average rate. Those utilities drawing more to serve more populous markets will thus pay more than those serving less populous markets. Since the tariff tracks electricity consumption, generators such as wind producers do not pay. FERC stipulated that MISO provide annual reports on the status of each MVP, detailing its costs and benefits for utilities as realized by the time of the report.158 If the report reveals benefit quantity differing from

149. MVP Order, 133 FERC at ¶ 62,094.
150. Compliance Filing, supra note 148, at 3.
151. Id.
152. See MVP Order, 133 FERC at ¶ 62,091. For projects carrying 345 kV or more, 20 percent of costs were socialized throughout MISO, with the remaining costs allocated subregionally among the affected pricing zones. Id. Projects below 345 kV received entirely subregional allocation, based upon line outage distribution factor analyses. Id.
153. See Illinois II, 721 F.3d at 772.
154. Id.
156. Illinois II, 721 F.3d at 772.
157. Id.
158. Id. at 774; MVP Order, 133 FERC at ¶ 62,097.
a utility’s respective MVP tariff, FERC may “modify or rescind” its approval.159

B. FERC’s Cost Causation Analysis: Approved

Illinois and Michigan utilities objected to the tariff on cost causation grounds. Illinois utilities contended that the criteria for choosing MVPs were too broad, allowing certification for cost socialization of projects benefiting only a few.160 They further contended that the MVPs as a whole would not confer benefits greater than costs, nor would they survive individualized cost-benefit analysis.161 Distinct from Illinois, Michigan utilities asserted their unique position as drawing only little power from the MISO grid.162 They contended that since Michigan law prohibits fulfillment of state renewables requirements from out of state sources, the MVP’s transmission of wind energy would uniquely not benefit them.163

Responding to Illinois utilities’ individualization contention, the court sympathetically observed, “none of these [MVP] eligibility criteria ensures” that every utility in “MISO’s vast region will benefit from every MVP project,”164 citing Illinois power cooperatives exempt from the state’s RPS requirements.165 Even acknowledging such subregional variation, the court nonetheless deferred to FERC’s assertion of MVP grid-wide benefits “relating to reliability and the provision of benefits across pricing zones.”166

Affirming FERC’s cost causation compliance, the court cited MISO’s estimates that the MVPs would generate cost savings of $297 million to $423 million annually, because of the lower cost of western wind power carried by MVPs compared to existing sources.167 Further, through reduced transmission losses, the MVPs would save $68 million to $104 million annually, plus an additional $217 million to $271 million annually in reduced reserve margin loss.168 The court emphasized that the steady advance of wind power secures continued cost savings, and, importantly, that these savings are grid-wide—”[t]here is no reason to think these benefits will be denied to particular subregions of MISO.”169 Last, the court reasoned, “other benefits of MVPs, such as increasing reliability of the grid . . . can’t be calculated in advance, especially on a subregional basis, yet are real” and will benefit all MISO subregions.170

159. Illinois II, 721 F.3d at 774.
160. Id.
161. Id.
162. Id.
163. Id. at 775–76.
164. Id.
165. Id.
166. Id.
167. Id. (citing MVP Order, 133 FERC at ¶ 62,095).
168. Id.
169. Id. at 775.
170. Id.
Addressing utility complaints over matching of costs to benefits, Judge Posner explained, “if crude is all that is possible, it will have to suffice.”171 Addressing Michigan, the court similarly remained unmoved, given FERC’s presented grid-wide benefits, quantified and asserted. The Illinois II holding thus establishes that quantified, though crude, grid-wide economic and loss reliability benefits—coupled with articulable and plausible reasons for additional grid-wide benefits, such as the advancement of wind power—are sufficient to socialize transmission costs.

The court’s application of the cost causation principle here adheres to its own precedent in Illinois I. In Illinois II, FERC provided quantified, grid-wide reliability and economic benefits, established by MISO studies, not the Commission’s analysis.172 Distinct from Illinois I, here the Commission did not “merely assert” enhanced grid-wide reliability resulting from added high-voltage transmission, thereby justifying cost socialization.

However, FERC’s lack of utility-by-utility cost-benefit analysis pits its “ballpark” benefits figures—supplied by MISO—against utility allegations that the figures violate individualized cost causation. Provided quantification, the Seventh Circuit did not hesitate to apply the quantified benefits across all MISO utilities. The question becomes, then, whether such broad strokes can satisfy cost causation, despite subregional variation. Predictably, such cost causation compliance has produced individualized litigation, underscoring the ambiguity surrounding identification of transmission beneficiaries in relation to the costs allocated them.173

C. Implications for Distance-Transmitted Renewables

The Illinois II holding seems to present an open door for wind investment in MISO, and arguably other RTOs. MVPs enhance grid-wide reliability and will likely confer currently indeterminable benefits as wind power advances, thus benefiting all grid members regardless of differing public policy requirements, reliance on non-MISO grid transmission, and varying willingness to pay for renewables. MVP costs therefore receive permissible socialization. Rather than face a patchwork of varied utilities, each with differing interest in renewables generation and differing ability to pay for it, wind generators receive near-guaranteed transmission funding, footed by the entire MISO customer pool. MISO investment conditions now present a significant boon to

171. Id. at 775.
172. MVP Order, 133 FERC at ¶ 62,095; Illinois II, 721 F.3d at 774. These studies were not entered into the record before the Seventh Circuit. Rather, FERC included them in its opinion approving the MISO tariff.
173. Two groups of MISO-affiliated parties petitioned for certiorari—the Michigan Attorney General with various Michigan utilities and industry groups, and a collection of Illinois, Kentucky, Michigan, Missouri, Montana, Wisconsin, and Indiana utilities. They sought review the Seventh Circuit’s Illinois II cost causation analysis on grounds that it lacked sufficient individualized analysis to fulfill cost causation, splitting with the D.C. Circuit’s alleged adherence to such analysis. The Supreme Court denied certiorari to all petitioners. See supra note 30.
the wind energy industry, within a geographic region replete with wind. Further, socialization provides utilities and consumers with a likely incentive to increase energy efficiency. Lowered total draw from the MISO grid produces a lowered MVP tariff; any enhancement in efficiency would allow utilities to draw less. It is less likely that such savings would incentivize individual customers, since individual reductions in power use to reduce draw would reflect a miniscule individualized savings.

In petitioning for certiorari, Michigan and Illinois utilities asserted that the Seventh Circuit’s Illinois II cost allocation is an unprecedented violation of cost causation since wind generators, who are parties clearly benefiting from the new transmission, will pay nothing. But such allocation adheres to the longstanding national practice of “load pays”—end users, rather than generators, pay for new transmission construction. Numerous other MISO generators have enjoyed transmission costs footed by load only. Unbundling and renewables investment have led to more frequent entry and exit from grids by generators, often requiring transmission construction. This arguably makes generators beneficiaries of new projects. While such conditions may support reconsideration of the load pays policy, petitioning utilities fail to raise such conditions as their reasons for demanding allocation to generators.

Renewables advocates should not, however, overlook utilities’ critiques of the Illinois II holding. While the asserted benefits meet the court’s bar as set by Illinois I, their imprecision and estimated nature belies any certainty that they will accrue to all MISO utilities in a manner roughly commensurate to per-utility tariff costs. First, those utilities relying primarily on non-MISO transmission reasonably contend they will not enjoy MISO grid-wide reliability benefits in the same amount as utilities relying exclusively on MISO transmission. The load-share ratio tariff does not account for such subregional differences. Utilities relying primarily on non-MISO facilities could, oddly, pay more for MVPs than MISO-exclusive utilities. Conversely, non-MISO utilities might enjoy small draws from the MISO grid and therefore still pay costs potentially commensurate with the degree of benefits. In either case, socialization continues to test cost causation when individualized utility analyses enter the record. As Judge Posner conceded, “it’s impossible to allocate these cost savings with any precision” across MISO members.

Second, in the court’s words, MVP benefits are subject to the “limitations

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175. See PJM INTERCONNECTION, supra note 2, at 1, 4, 23–24.

176. See Brief for Petitioner, Schuette, supra note 155, at 5; Brief for Petitioner, Hoosier Energy Rural Elec. Coop, Inc., supra note 174, at 6, 10.

177. This would occur if a primarily non-MISO utilities’ total draw from the MISO grid exceeded those of MISO-grid-exclusive utilities. While a given non-MISO utility might draw a greater portion of its power from non-MISO grid, its total MISO draw could still exceed that of a MISO-exclusive utility—especially one serving a low-population territory.

178. Illinois II, 721 F.3d at 774.
on calculability that the uncertainty of the future imposes.” While wind investment may be advancing, the extent to which it will confer economic and reliability benefits is uncertain. Significant technological questions remain regarding the extent of wind benefits. These include whether weather patterns allow for generation at needed intervals to offset losses and outages and whether storage technology can mitigate fluctuations in wind energy production. Moreover, two emerging national-scale grid options are influential in the degree to which distance-transmitted renewables will advance. These are (1) vast use of trans-region high-voltage transmission to create a national “supergrid” specially geared toward carrying renewables power from remote generation to population centers, or (2) regional identification of discrete, necessary transmission projects to carry the power to individual loads. The MISO MVPs follow the latter. While uncertain, evolving broader grid structure might eventually necessitate departure from or alteration of the MISO MVP transmission approach.

III. THREE UNANSWERED TRANSMISSION ALLOCATION QUESTIONS

The following areas, if clarified by Congress or FERC, would provide RTOs and member-utilities with needed guidance in transmission cost allocation, significantly reducing litigation and creating stable investment scenarios for renewables investors. Either Congress or FERC could provide such clarification; each possesses unique abilities to do so.

There is a notable reason why Congress should provide the clarification. Emerging from elected representatives as opposed to an independent regulatory commission, congressional cost allocation direction related to renewables may carry more credibility than FERC action. Such credibility might insulate congressional action—to some degree—from the ongoing litigation that has frequently met FERC oversight and rulemaking on transmission/grid planning.

However, there are also various reasons why FERC should provide the clarification. Legislators lack FERC’s specialization and expertise in addressing an area of sustained and increasing complexity. Very few members of Congress have dealt with cost allocation. Senator Bob Corker’s amendment attempts—first to S. 1462 in the 111th Congress and, second, to the FPA during the 112th Congress—largely represent the extent of recent congressional

179. Id.
181. Klass & Wilson, supra note 7, at 1811–12 (discussing the challenges posed by wind power integration, including storage and transmission).
183. Id.
184. See Maser, supra note 11, at 1853 (“It is concerning that an independent agency lacking direct political accountability continues to push the envelope into controversial areas. Politically accountable federal legislators would be more appropriate arbiters of these issues in the first instance.”).
involvement. The first amendment drew the ire of then-FERC chairman Jon Wellinghoff on the grounds that it would prevent cost spreading when legal and necessary, and tie FERC in needless litigation. If Congress weighs in on which benefits may enter cost causation analyses, similar exchanges seem inevitable. FERC rulemaking, by contrast, may be less prone to inter-branch discord, unless its promulgation and/or contentiousness compels a congressional response, preempting or otherwise obviating it. FERC has shown understandable scrutiny toward attempts to alter the language it must interpret, and has not hesitated to articulate resulting impacts upon broader agency tasks.

Also supporting FERC action, Congress’s fact-finding, research, and briefing capacities may not match those of the agency on cost allocation. A bill providing lasting and comprehensive guidance would therefore require some effort by Congress to decipher cost allocation dilemmas, lest the bill receive much of its substance from nonlegislators. Moreover, political realities might prevent Congress from passing comprehensive cost allocation legislation or might dictate a piecemeal approach involving amendments to the FPA and other bills. Given the impact of cost allocation policy on renewables investment, guidance could take the form of a renewables bill, addressing cost allocation secondarily. Such legislation appears unlikely given present congressional gridlock.

Issuing such guidance may also be frustrated by the bounds of FERC’s power over interstate transmissions. Section 206 of the FPA empowers FERC to establish a “just and reasonable” rule, regulation, or practice “to be thereafter observed and in force,” and to “fix the same by order.” As for Order 1000, this section provides FERC sufficient authority to prescribe detailed cost

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185. See, e.g., S. 400, 112th Cong. § 1 (2011) (not enacted) (amending section 205 of the Federal Power Act); American Clean Energy Leadership Act of 2009, S. 1462, 111th Cong. § 121 (2009) (not enacted); CAMPBELL & VANN, supra note 16, at 10. The Corker amendments sought to limit FERC’s ability to allocate costs to “measurable economic and reliability benefits,” thus targeting the agency’s ability to utilize benefits not easily quantified to satisfy cost causation. S. 1462. In addition to the Corker amendments, Rep. James Sensenbrenner of Wisconsin sponsored the Powering America for Tomorrow Act, first introduced in the House during the 112th Congress and reintroduced as H.R. 2762 during the 113th, yet to emerge from committee. See supra note 12. Broadly, the Act seeks to streamline regional transmission planning processes. Significant for transmission cost allocation, the Act directs FERC to require that: (1) all regional high voltage electric transmission cost allocation methods adhere to a clear and consistent set of specified regulatory principles; and (2) regional transmission planners coordinate planning across regional boundaries within an Interconnection. In pertinent part, the principles governing cost allocation provide that the costs of transmission construction would “be allocated consistent with the range and distribution of benefits within the designated region that are provided by such facilities, the use of the transmission system, or with other equitable and economic considerations.” Powering America for Tomorrow Act, H.R. 2762, 113th Cong. § 2 (2013) (as referred to House Subcommittee on Energy and Power, July 6, 2013).


187. Id.

allocation guidance and/or prescribed practices. FERC has thus far refrained, electing to preserve maximum regional flexibility over cost allocation as implemented by each RTO and ISO. Given the vast intricacies of these organizations and the large geographic regions some serve (like MISO), FERC’s hesitance is reasonable. Uniformity in cost allocation procedures beyond project identification stages (the reach of Order 1000) might tie agency hands in reviewing rates affecting vastly disparate customer pools. FERC differs from Congress here. Unlike the agency, legislators do not review interstate cost allocation schemes and craft legislation to clarify cost allocation parameters while leaving the specifics of their application to the reviewing agency. FERC thus likely seeks to guard its discretion while performing FPA section 205 review.

As indicated by the reception of Order 1000, any rulemaking will face much litigation, postponing and potentially threatening its effectiveness. Notwithstanding, certain allocation ambiguities can stand clarification without contravening necessary local allocation flexibility. As in the past, a standard comment period would allow FERC to heed regional differences while still implementing guidelines that facilitate the construction of urgently needed new transmission.

A. Definition of “Benefits” under FERC Order 1000

Order 1000 allows for consideration of various potential benefits of transmission projects, including economic and reliability benefits, but provides no definition of “benefits.” FERC effectively allows RTOs to determine the targeted benefits per transmission project and thus the beneficiaries who will pay their roughly commensurate costs. The Commission explained, “the proper context for further consideration of these matters is on review of compliance proposals and a record before us.”189 In Illinois II, the court mentioned in dicta that the MISO-territory states’ RPS requirements acted as drivers for the MVP portfolio.190 The court did not include RPS fulfillment as a benefit in its cost causation analysis.191

A definition of benefits, whether supplied by Congress or FERC, would

189. See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 Fed. Reg. 49,842, 49, 938, 136 FERC ¶ 61,051 (July 21, 2011), available at https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf (”[T]he Commission is not prescribing a particular definition of “benefits” or “beneficiaries” in this Final Rule. In our view, the proper context for further consideration of these matters is on review of compliance proposals and a record before us. Moreover, allowing the flexibility to accommodate a variety of approaches can better advance the goals of this rulemaking.”).
190. Illinois II, 721 F.3d at 772 (”Every state in MISO’s region except Kentucky . . . encourages or even requires utilities to obtain a specified percentage of their electricity supply from renewable sources, mainly wind farms. Indiana, North Dakota, and South Dakota have aspirational goals; the rest have mandates. The details vary but most of the states expect or require utilities to obtain between 10 and 25 percent of their electricity needs from renewable sources by 2025—and by then there may be federal renewable energy requirements as well.”).
191. Id. at 773–76.
provide a more precise framework for allocating costs, lowering post-allocation litigation and creating a more uniform and predictable renewables investment atmosphere. Such a definition should be promulgated, and should include all currently identified transmission project benefits, including the fulfillment of state RPSs. Given that utilities already must comply with the public renewables policies of their states, FERC has a strong argument in favor of a definition that explicitly includes RPS fulfillment. Similarly, a functional definition from Congress would have to acknowledge the degree to which states’ public policies themselves have necessitated interstate renewables transmission, and the geographic needs of wind energy, which may require interstate transmission construction to fulfill those policies.

Environmental benefits secured through transmission construction, however, present a benefits definition dilemma. Transmission integrating renewables into an RTO may produce cognizable environmental benefits for RTO ratepayers, generally in the form of reduced carbon emissions within their territories.192 However, such positive externality benefits also accrue societally, beyond the territory of the RTO building the transmission. Unlike economic, reliability, or RPS-fulfillment benefits, environmental benefits present quantification difficulties—in terms of both monetary amount and precise demarcation of groups benefiting. Long-term visions of the national grid incorporate environmental benefits as desirable; some short-term construction planning processes already incorporate them.193 Yet, such amorphous, societal benefits are not included in cost causation analyses. Inclusion of these benefits in a benefits definition—supporting their incorporation within cost causation analyses and the resulting rates funding transmission—would likely require congressional spearheading.

A broad definition would not bind customers into funding projects securing only unquantifiable benefits. In such instances, it would fall upon courts to weigh all benefit and cost evidence in the record on a project-specific basis. Courts could then determine the weight of such evidence, in light of the existing legislative and state public policy context, if Congress supplies the definition, or the agency rulemaking context, if FERC does.

B. Individualized Benefits-to-Costs Assessment

Congress or FERC should prescribe the degree to which individualized, per-utility benefit-cost assessment must underlie proposed transmission plans.

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193. PMJ INTERCONNECTION, supra note 2, at 22; Klass & Wilson, supra note 7, at 1870–71 (discussing the MISO MVP plan’s recognition that benefits accrue “not just due to reliability and economic impacts, but also due to the achievement of various state and regional policy goals,” including RPSs).
As highlighted by Judge Posner, benefits assessments may encounter technological limitations, given the inherent difficulty of calculating precise system-wide benefits and their accrual to individual utilities. FERC might object to the large administrative challenge or potential for redundancy in conducting its own individualized assessment for every utility within a given cost socialization region. MISO conducted such analysis prior to the issuance of the MVP plan, likely lending important weight to its assertion of MVP cost causation compliance before the Commission. As evidenced by *Illinois I* and *Illinois II*, the Commission has relied on system-wide benefits data, not individualized data, to justify cost socialization. Such system-wide data is likely less expensive and logistically demanding to accumulate, though may be more prone cost causation objections and related litigation by utilities facing regional cost sharing plans.

C. Benefits Analysis and Tariff Review

If assessed with sufficient frequency—per legislation or FERC order—tariffs could receive frequent revision to closely track the accrual of quantifiable benefits to ratepayers. While FERC analyzes cost causation compliance upon tariff plan review, such tariff tailoring would address imperfect allocations based upon (understandably, often out of necessity) benefit projections rendered uncertain by “limitations on calculability that the uncertainty of the future imposes.” Still, cost and logistical obstacles might arise. First, pursuant to the FPA, any revisions would require FERC review. Given the cost causation standard—"roughly commensurate"—a tariff revised to closely match the accrual of quantifiable benefits would likely receive FERC approval and withstand any subsequent judicial review. However, an RTO’s revision process could be lengthy and costly, depending on geographic size, governance structure, and number of impacted stakeholders, among other factors. Second, transmission projects require complete construction before their benefits levels become certain, eventually supplanting pre-construction benefits estimates. The most reliable data suggesting adjustments to tariffs would therefore likely only become available some time after project construction—funded by tariffs potentially achieving less-than-maximum adherence to cost causation.

CONCLUSION

Transmission cost allocation presents a significant hurdle to a majority-renewables national electricity system. The allocation methods discussed in this Note are only departure points for evolving solutions to renewables integration.

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195. *Illinois II*, 721 F.3d at 774.
196. *See* 16 U.S.C § 824d(d), (e) (2012).
Numerous transmission organizations already employ allocation methods that combine two or more methods for a given pool of costs. In the absence of Commission or congressional action, the laboratory of RTOs, ISOs, states, utilities, and ultimately power customers will, of necessity, step forward to address cost allocation challenges. Such a solution would not be catastrophic, but would entail considerable and unnecessary transmission construction delays.

We welcome responses to this Note. If you are interested in submitting a response for our online companion journal, Ecology Law Currents, please contact ecologylawcurrents@boalt.org. Responses to articles may be viewed at our website, http://www.boalt.org/elq.